414 Nicollet Mall
Minneapolis, MN 55401

April 1, 2014

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: ANNUAL REPORT
SMART GRID
DOCKET NO. E999/CI-08-948

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Smart Grid Annual Report in compliance with the Commission's June 5, 2009 Order and the March 4, 2011 Notice in the above-referenced docket.

In compliance with the above requirements, we have also provided this information as Attachment K to our Minnesota Rules Annual Service Quality Report in Docket No. E002/M-14-131 filed on April 1, 2014.

We have electronically filed this document with the Minnesota Public Utilities Commission and copies have been served on the parties on the attached service list.

Please contact Amber Hedlund at amber.r.hedlund@xcelenergy.com or (612) 337-2268, or me at paul.lehman@xcelenergy.com or (612) 330-7529 if you have any questions regarding this filing.

Sincerely,

/s/

PAUL J LEHMAN

MANAGER
REGULATORY COMPLIANCE & FILINGS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF COMMISSION CONSIDERATION OF STANDARDS RELATED TO SMART GRID INVESTMENTS AND INFORMATION UNDER THE FEDERAL INDEPENDENCE AND SECURITY ACT OF 2007

DOCKET NO. E999/CI-08-948

ANNUAL REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Annual Smartgrid Report for the 2013 calendar year. We submit this Report pursuant to the Commission's June 5, 2009 Order and March 4, 2011 Notice in this Docket and note that we concurrently filed this report as part of our April 1 Electric Service Quality Annual Report under the Minnesota Rules.

We respectfully request the Commission accept our 2013 report, which includes the following information, in compliance with the Commission's Order and Notice:

- Past, current, and planned smart grid projects, specifically including:
  - A description;
  - Total costs;
  - Cost effectiveness;
  - Improved reliability, security, system performance; and
  - Societal benefit.
- "Smart" functions enabled with existing infrastructure and systems (including what percentage of the utility's meters are currently mechanical, AMR, or AMI, and a sentence on the capability of each);
- Planned or completed system improvements which could affect customer

service, power quality, or service quality metrics;

- Current customer access to data (such as usage or outage data) and how that data educates customers; any planned additional customer access to data;
- Time-varying rates and demand response; and
- The general costs of completed or planned projects (include the costs of changes to billing systems and, if applicable, the early retirement of meters or other equipment) compared to the benefits realized or expected to be realized.

We additionally provide an expanded discussion of Electric Vehicle initiatives, in response to previously-expressed interest in this topic in this docket.

ANNUAL REPORT

Change is underway in our industry, including technological advances, environmental pressures, and increasing customer expectations. At the same time, operating our system is a complex matter. Therefore, while technology is enabling a smarter and more resilient electric power grid, it is critical that we take a measured approach to harvest the best value for our customers as we identify new and better ways to provide our customers with high quality service, meet increasing environmental requirements, and implement advancements and standardized processes that enhance the overall safety of our operations.

Smartgrid has been described as the integration of a communications network with electrical and natural gas equipment, resulting in overall improved efficiencies, management capabilities, and customer value for the electric and natural gas systems. Our approach to "smart grid" is to learn from the current deployments, both internal to Xcel Energy Inc. and within the industry, and implement initiatives at the pace of value to our customers and operations. In this report, we discuss emerging and ongoing initiatives that relate to "smart" functions and capabilities, as well as initiatives that relate to the changes that are underway in our industry.

A. New and Emerging Initiatives

We generally discuss our new and emerging initiatives in this section. We discuss our existing intelligent infrastructure and any related 2013 updates in Section B of this Annual Report.

1. Network Communications Strategy

In our most recent Annual Report, we discussed an effort we had undertaken to define a strategy that would support our current and expected future data needs for our transmission and distribution substations, distribution system automation, natural gas and electric meter reading, and natural gas operations. We noted that the network would need to incorporate multiple levels of communications architecture to securely and efficiently handle the varying data needs of these essential Company operations.

In 2013, we completed the work on our strategy, and developed a framework within which we expect to:

- Ensure security and compliance;
- Leverage our current assets;
- Increase the speed, reliability and access to operational data; and
- Optimize performance monitoring and response while controlling cost.

In developing this framework, we used our knowledge and experience gained from previous deployments, other utilities, and vendors – combined with our objective of fully leveraging the assets we already have in place. We also factored-in the need and challenges associated with preparing the distribution system for the impacts of increasing amounts of Distributed Generation (DG). We answered questions such as: (1) how we manage the complexities of differing communications and equipment infrastructure in the different operating companies; (2) how we ensure the most cost-effective, secure, and value-added network possible; and (3) how we best manage the costs of the system preparations associated with DG, such that they are incurred as close as possible to the actual deployments of DG.

Finally, we recognized that it would be vital that cyber- and physical-security be designed-in, and not added as an afterthought or in a reactive manner. This is especially critical as the technologies used in our operational and information systems converge. In the past, when these areas had very different underlying technologies, there was an additional measure of security provided by the dissimilarity. However, in a converged and standardized environment, only a well thought out and implemented multi-layer security environment will protect our critical assets.

a. Our Network Communication Strategy

Our Network Communication Strategy is to update our communications infrastructure in incremental steps based on a common set of design, control, and security principles. These steps will ensure that all field data passes through Hubs (the appropriate *substation* for electric and *pressure regulator* in the case of natural gas) and then to central systems, using the most cost-effective transport, so that in the future, as the Hubs become increasingly intelligent, they can facilitate decisions and actions closer to where the system conditions and events are occurring in the field. Our Network Communications Strategy provides the foundation for our continued implementation of smart technologies that benefit the Company and our customers.

b. How the New Strategy Differs

Previously, we implemented networks using a *functional* approach, with each network optimized for a particular environment (electric SCADA, gas SCADA, device monitoring, etc.), and typically sending the data from the field to a central system. While this was very effective for the conditions at the time they were constructed, in the future, and particularly with greatly expanded DG on the system, it will be essential for the system to make decisions much closer to the conditions occurring in the field. This is necessary in order to respond in a secure and appropriate manner that protects the rest of the system.

To achieve our new strategy, we need to be able to transport massive amounts of data between numerous field locations while managing our costs. We believe the Hub concept is the most cost-effective way to achieve the levels of field/operational intelligence we now anticipate, as well as to support the further operational intelligence inevitable in our industry – and that will be necessary to identify new and better ways to provide our customers with high quality service, meet increasing environmental requirements, and implement advancements and standardized processes that enhance the overall safety of our operations.

c. Implementing the Strategy

As part of our strategy work in 2013, we decided that we must first establish a new operational model for network communications that will scale and support business initiatives as they are implemented. The Principles that provide the framework for implementation of our Network Strategy and communications model are as follows:

- Maximize leverage of our assets, while optimizing public carriers;
- Design multilayer security and compliance into the systems from the start;
- Have a single point of control and monitoring (i.e., operations center);
- Hub all field data through substations;
- Use common tools, processes, equipment templates and standards across the enterprise;

- Have a clear governance model that supports cross-functional alignment;
- Design for redundancy, multiuse, and traffic control;
- Maximize cross-functional joint use of facilities; and
- Implement at the speed of value to our customers, with business requirements driving deployment.

With our strategy in place and the structure of a new scalable operating model near completion, we are positioned to execute incremental initiatives that we believe will deliver the greatest value to the Company and our customers. Our initial initiative will introduce a common Network Operations Center (NOC) as a point of control and "incident management" for all operational communications, regardless of which functional area of the company operates them. In parallel, we are also building a common set of tools for planning, designing, monitoring and troubleshooting our communications systems.

We then expect to turn our attention to increasing our communication capabilities with our Hubs, using our own fiber optic assets. This increase in capabilities will help us make more informed, real-time decisions on our electric transmission loads, and increase our effectiveness in predicting faults, rather than reacting to them after they occur. Further, we will work with the operational business areas as they identify opportunities to increase their operational capabilities through increased system intelligence, such as the initiatives discussed in Part 2 of this section, and implement those initiatives at the speed of value to customers. We continue to believe it is important to take a measured, incremental approach to ensure that we balance cost with our need to continue to meet our reliability requirements and provide our customers with high quality service.

d. Expected Benefits

We continue to expect the primary benefit of implementing a comprehensive communications network to be improved efficiency through increased standardization, monitoring and remote control of our system in a secure manner. For example, we expect to consolidate existing field area networks, and leverage our substations as communications hubs, aggregating data from field devices; this reduces the number of separate networks that must be monitored and maintained. Additionally, as with any change, we will take advantage of the opportunity to ensure we are applying the latest security protocols. Our network strategy will continue to be a key foundational program for our continued implementation of smart technologies that benefit the Company and our customers.

2. *Enhanced System Monitoring and Control*

We use an Energy Management System (EMS) to monitor and manage the automated devices on our distribution and transmission systems. The Supervisory Control and Data Acquisition (SCADA) element is the primary function of the EMS, and is shared by transmission and distribution. SCADA facilitates real time two-way communications from field devices, and provides Transmission and Distribution Operations the ability to remotely control the flow of electricity during outage and maintenance periods, and collect information about the health of the system.[1]

We have determined that it is necessary to replace our current EMS, which was originally installed in the mid-1990s. The level of customization we have had to do to the system to meet the changing transmission regulatory environment and market structure has undermined the system's reliability, and caused Critical Infrastructure Protection (CIP) compliance and security challenges. The new generation of EMS builds-in CIP as a fundamental part of the design, as opposed to the "bolt-on" approach that we have had to take with our 1990's vintage EMS. In addition, the latest generation of EMS contains many enhanced functional improvements in the basic SCADA function, and improved support for advanced application functions that standardize Operator capabilities and approach, as well as adding additional functionality regarding circuit management.

We selected General Electric's PowerOn Advantage EMS, and are currently developing the database and user graphic displays for the NSP System (NSPM and NSPW transmission, generation and distribution facilities). During 2014, the project will progress through testing, and is expected to go-live in early 2015. We summarize the SCADA functionality of the EMS in Part a below, and discuss some of the advanced functions that the transmission and distribution operational areas are planning and implementing in Parts b and c below.

a. SCADA Functionality

In summary, our SCADA system provides information to control center operators regarding the state of the system, and alerts when system disturbances occur, including outages. Every few seconds, it provides system status information, such as normal operating parameters for our generation and substation facilities. It also immediately notifies an Operator of disturbance types (sustained or momentary event), so that system impacts can be assessed and operations can take appropriate

[1] The transmission system is fully automated, and currently, the distribution system is generally automated at the Feeder level and above.

action to restore service to our customers. Our SCADA system also monitors and collects system performance information for Feeders and Substations. This information is used by transmission and distribution operations to ensure the system is safely and efficiently operating within its capabilities. The performance information is also used by planning Engineers to perform load and operating analyses to establish system improvement programs that ensure we adequately meet load additions and continue to provide our customers with strong reliability.

In summary, our use of SCADA technology improves outage restoration, system performance, and planning engineering, which translates to providing safe, reliable, and adequate service to our customers. In our 2012 Annual Report, we noted that we expected to enable and integrate a portion of SCADA information into our Network Management System (NMS, f/k/a Outage Management System or OMS). However, we are now planning to implement an Advanced Distribution Management System (ADMS), which will integrate SCADA, NMS, and several other systems to provide a robust decision support system to assist control center, field, and engineering personnel with the monitoring, control and optimization of the distribution system. We discuss ADMS in Part c of this section.

b. Advanced Transmission Functions

The coverage of the GE EMS is similar to our current EMS, with one minor exception – the real-time energy scheduling and hourly energy accounting for Midcontinent Independent System Operator (MISO) market settlement. These functions tend to be unique to each utility, so are not standard components of EMS software. We are therefore separately developing these functions in parallel with the EMS development in a new consolidated Integrated Energy Management (IEM) system. We believe separately developing these energy accounting functions provides improved ability to focus on the development of core EMS/SCADA and IEM functionality, and increases our ability to manage the risk associated with transitioning to the new EMS/SCADA system.

A couple of the advanced applications we are developing in conjunction with the EMS/SCADA system are Network Connectivity Analysis (NCA) and Operator Training Simulator (OTS). The NCA creates a model of the electrical system connectivity every five minutes and tests 500 scenario contingencies. This gives Operators and opportunity to see any voltage excursions and any lines that may be overloaded – allowing them to take action to avoid an event occurring on the system.

The OTS is able to simulate events, including past actual events for training purposes. We use OTS as part of our annual training and reliability drills – and note that we used this system in conjunction with our participation in the North American Electric Reliability Corporation (NERC) GridEX II national grid security exercise in November 2013. GridEX II was the largest, most comprehensive effort addressing security by the electricity industry to-date, and included over 234 organizations with more than 2,000 individuals as well as government agencies such as the Department of Homeland Security, FBI, and Department of Energy (DOE). It was a simulation of a coordinated cyber and physical attack on the bulk power system, impacting corporate and control networks and concurrent physical attack that degraded reliability and threatened public health and safety.[2]

The forecasted NSP System costs of the new EMS/SCADA and IEM are approximately $12.4 million.

c. Advanced Distribution Management System

Also concurrent with development of the new EMS/SCADA, we are planning an Advanced Distribution Management System (ADMS) project, which is the distribution equivalent to the advanced transmission functions discussed in Part b above. One of its functions will be to integrate with the EMS/SCADA to provide an integrated operating and decision support system to assist control room, field personnel, and engineers with the monitoring, control and optimization of the distribution system. While some elements of the transmission and distribution system benefit from an integrated SCADA, the ADMS SCADA integration will increase the ability of distribution operations to manage and monitor those elements that are unique to the distribution system.

While our current distribution SCADA capabilities go to the Feeder level, with ADMS, we will be able to implement automation to the Tap level on some portions of our system.[3] In addition to the enhanced SCADA capabilities, and similar to the advanced application capabilities for transmission, the ADMS will enable the Company to develop applications that aid in managing the complex interactions that are part of both planned and unplanned outage events, feeder switching operations, and device loading.

We are initially investigating two applications enabled by ADMS that we believe will provide the Company and our customers the greatest value: (1) The FLISR application locates faulted sections of the system (Fault Location) then automatically

[2] *See* http://www.nerc.com/pa/CI/CIPOutreach/Pages/GridEX.aspx for additional information.

[3] Taps are one level below Feeders on the Distribution system. In general, Feeders serve thousands of customers and Taps serve hundreds.

isolates the faulted section (Isolation) and restores power to as many customers as possible (Service Restoration), resulting in reduced outage durations for a portion of customers;[4] and, (2) Integrated Volt Var Optimization (IVVO). Initially IVVO will replace the existing controls to reduce system losses by controlling capacitor banks to improve power factor on feeders. Its controls will also ensure distribution feeder voltage for improved power quality. Finally, it will be capable of integration with voltage regulation equipment, which can then enable voltage reduction to reduce loading during system peak demand and emergency loading situations. We are continuing to explore these applications enabled by the ADMS, and will implement them at the speed of value to our customers.

There are many benefits associated with ADMS to be realized with greater future investments in intelligent electric field devices including *reliability improvements* such as faster restoration times, improved storm response and restoration, and improved outage and restoration information; *power quality monitoring* to quickly identify problems and maintain compliance and equipment performance; *safety measures* such as ensuring distributed generation isolation during outages, decreases in drive time and avoided trips, and improved tagging and switching management; *operational efficiencies* such as reduced fault investigation time, reduced crew time for fault location, isolation and restoration, improved situational and operational awareness, and optimized switching; *conservation and energy efficiency,* such as reduced peak demand and reduced electrical losses; and, *asset optimization* such as improved analytics and remote diagnostics of intelligent equipment.

The NSPM 2013 costs associated with the ADMS planning stage were approximately $77,000 in Capital and $30,000 in O&M.

3. Outage/Network Management System

In 2012, we completed a significant upgrade of our Network Management System (NMS), which is the system we use to manage planned and unplanned distribution system outage events. Among other things, the upgrade allowed for further leverage of our Automated Meter Reading (AMR) system by integrating our ability determine whether a customer has line-side power directly into NMS. We do this by "pinging" the meter by accessing a field controller that is part of our AMR system, which polls the individual customer's meter to determine whether it is energized.

[4] NSPM currently has FLISR capability on certain segments of the system where "teams" of switches communicate with each other to perform the function. FLISR controlled by ADMS will provide enhanced capabilities. We discuss current system intelligence in Section B of this Report.

The pinging itself eliminates crew trips that would have otherwise resulted in an "okay on arrival" outcome. During 2013 in Minnesota, we were able to use this capability to verify that the customers associated with more than 1,000 outage jobs were energized, then cancel those jobs – making this tool a proven critical resource in restoring service to our customers as efficiently and quickly as possible. The integration of this functionality directly into NMS also improved our control center efficiency, as previously, employees had to use a separate system to perform the pinging.

As noted in Item 2 above, the NMS, along with a number of other systems will be integrated into our ADMS, which we expect will further improve our efficiency and service to customers.

4. Solar on Network Pilot Results

Secondary distribution networks are used in downtown Minneapolis and St Paul to serve high-density loads with high reliability. The control systems for these networks rely on power flowing toward the customer, a state that can be reversed with distributed generation. While many utilities have disallowed solar/photo-voltaic (PV) distributed generation (DG) on networks for this reason, we approved two installations in 2012 on a pilot basis. We, however, required specific controls be installed to ensure directional power flows remained adequate to forward-bias the controlling relays.[5] The pilot PV units and their controls have performed well.

Concurrent with this pilot, Xcel Energy engineers created a Network Interconnection Guideline to address the technological concerns while maximizing permissible PV DG. The result provides for somewhat relaxed requirements for future installations. While less restrictive than the initial requirements, the modified requirements are essential to maintaining the integrity of the network. We will be presenting the findings from this pilot in spring 2014 to representatives from Minneapolis, St. Paul, and the Minnesota Department of Commerce.

5. SolarTAC: Solar-2-Battery and Community Energy Storage

Xcel Energy and EPRI are currently evaluating two battery energy storage systems at one of the largest dedicated solar research facilities in the United States: the Solar Technology Acceleration Center (SolarTAC) in Aurora, Colorado. Battery energy storage may be a key to increasing the reliability, efficiency, and value of variable renewable generation resources. In particular, the proliferation of solar PV is prompting utilities such as Xcel Energy to investigate effective grid-management

[5] If forward-bias of the relays is not maintained, the protectors open, which decreases reliability.

techniques for handling high-penetration solar conditions. Both of these multi-year research efforts aim to discern the technical and economic costs and benefits of utilizing energy storage for a range of transmission- and distribution-connected solar applications such as time shifting/peak shaving, ramp rate limiting, power smoothing, and voltage regulation.

Solar-to-Battery. Solar-to-Battery (S2B) is evaluating a 1.5 MW/1.0 MWh advanced lead acid system produced by Xtreme Power. We are assessing their Dynamic Power Resource unit interconnected with a number of concentrating PV arrays for its ability to perform multiple grid support operations at a larger scale. The arrays produce up to 780kW on the local distribution circuit. The support operations we are assessing have the potential to provide economically valuable grid benefits, including distribution upgrade deferrals, system capacity, energy time-shifting, and distribution voltage support.

Community Energy Storage. The Community Energy Storage (CES) project is demonstrating a 25-kW/50-kWh Sodium-Nickel-Chloride battery manufactured by FIAMM SoNick that is affixed to a model solar neighborhood. The solar neighborhood consists of PV arrays, load banks, metering equipment, and other components. We are studying the single-phase AC unit to assess its ability to provide impactful distribution applications at the residential customer level. The system's interconnection with the solar neighborhood along with a dedicated transformer, is intended to simulate real-world conditions that can more accurately portray this battery's various modes of operation.

Both the S2B and CES projects are first-of-a-kind. Currently, the units are successfully operating and generating data for analysis. However, we have encountered unanticipated challenges that have delayed testing. Efforts going forward will focus on executing test plans that we have learned work within the battery systems' limitations, and also discovering their full potential to provide valuable energy storage services at the neighborhood and substation/mid-feeder levels.

6. High Definition LiDAR Survey and Line Modeling

Light Detection and Ranging (LiDAR) survey consists of flying a helicopter over transmission lines with a laser to capture the existing conditions in the right-of-way. Additional sensors capture multiple images that are used to create an orthographic imagery, very similar to what is shown in Google Earth, and oblique images, very similar to what is shown in a Google Street View. We use this data to create an accurate GeoReferenced model of the transmission line and other objects in the right-of-way. From this model, we are able to verify electrical clearances, respond more quickly to storm damage, order materials, and design new construction, which reduces costs and improves reliability of the system.

LiDAR survey provides greater data quality and density than traditional survey, conducted on the ground with a field crew using optical instruments and GPS. In a single aerial pass, LiDAR can capture high definition data for a target corridor up to 300 feet in width, compared to a traditional ground survey that generally acquires a 50 to 100 foot width.

The traditional ground approach requires that we coordinate with landowners for access, and takes several months to survey 30-60 line miles, which we can do with LiDAR in a single day with no burden to landowners. However, the greatest advantages of LiDAR over traditional survey are cost and timeframe. The 2013 cost per mile for LiDAR was $800, versus a traditional survey cost of $2,000. This translates to a 2013 savings of $1.4 million.

We use the same LiDAR data to model the vegetation in the corridor to identify hazard trees, create routine maintenance work plans, and prescribe wildfire protection efforts, which result in reduced costs and increased reliability. Another major benefit the High Definition models are to update our Geographic Information System (GIS) with high accuracy data greatly enhancing the understanding and management of our system.

In 2013, we performed LiDAR on approximately 1,200 transmission line circuit miles in Minnesota. To-date, we have acquired LiDAR data on approximately 3,250 of the 4,000 miles of transmission lines owned and/or operated by Xcel Energy in Minnesota. We plan to continue our efforts to LiDAR survey and model lines as business needs arise, with a goal of ultimately having all transmission lines modeled based on LiDAR acquired data.

7. *Advanced Wind Production Forecasting System*

In 2013, Xcel Energy, already the nation's number one wind energy provider, proposed adding a total of 1,900 megawatts of additional wind resources – a 40 percent increase companywide – with 750 megawatts of that total planned for the NSP System. Ensuring that renewables are efficiently integrated into our operations is an important priority for Xcel Energy.

In 2009, Xcel Energy engaged in a multiyear R&D partnership with the National Center for Atmospheric Research (NCAR) to develop what has become WindWX –

one of the most advanced wind-production forecasting systems in the world. We now contract with Global Weather Corp. (GWC), an affiliate company of NCAR, to continue to host and maintain the system. The present state WindWX system uses real-time, turbine-level operating data and applies complex meteorological algorithms to forecast the amount of wind power that will be produced at all the wind farms throughout the Xcel Energy service territory.

The forecasts, now available worldwide, are designed to help utilities make better commitment and dispatch decisions, including opportunities to power down less-efficient power plants when sufficient winds are forecasted to help meet customer electric demands, and to optimize their market offers in organized markets such as MISO.

In 2013, we completed two full years of operational deployment of WindWX, and have been able to reduce the forecasting error by over 40 percent, and estimate the savings to NSPM customers at approximately $15.4 million through 2013. Building on previous project successes, Xcel Energy, NCAR, and GWC initiated a third phase of project work during 2013 to further enhance the sophistication of the technology. In this stage, we seek to improve short-term forecasting, focusing on ramping and extreme weather events, and introducing probabilities into the forecasting process.

Over the course of the next two years, NCAR scientists and engineers will develop custom forecasting systems to enable Xcel Energy to improve reliability by better anticipating sudden ramping changes in wind production, as well as better prepare our short-term planning when extreme weather conditions, such as icing, threaten our systems and impact the generation capability of the wind turbines.

Our partnership with NCAR and GWC has gone a long way to help us meet our priority of efficiently integrating renewables into our operations, and we expect our use of the WindWX system to grow the cost savings to our customers.

B. Existing Infrastructure and Programs

Over time, we have implemented a number of strategic projects that have improved the intelligence of the NSPM distribution system that positively affect customer service, power quality and reliability. However, as of now, we do not expect any direct results on our existing service quality metrics. The Network Communications Strategy we discuss in Section A will form the foundation that will allow the Company to expand and further leverage the intelligence of the system, which will allow us to further increase our effectiveness and service to customers. In this section, we discuss highlights of ongoing projects and intelligent features of our existing infrastructure that we previously implemented, as summarized below:

- *Automated Switch Teams* – automatically restores electric service to a portion of affected customers after an event, reducing the outage time.
- *Remote Fault Indicators* – reduces outage time by enabling restoration on un-faulted portions of the circuit without first making a site visit.
- *Smart Substation* – allows faster restoration times and provides increased system reliability from implementation of modernized technology and the decision-making capabilities it facilitates.
- *SmartVAR* – improves power quality and availability, and reduces system losses, which ultimately reduces fuel costs for all customers.
- *MISO Smart Grid Project* – improves power system reliability and "visibility" through broad-based system monitoring and control.
- *Wind-to-Battery* – could reduce the impacts of wind and potentially solar variability, allowing for improved integration of renewable energy into the grid.

In addition, as discussed in Section A, our NMS now leverages our AMR infrastructure, which has resulted in Company efficiencies and improved service to our customers through more efficient use of our crews.

1. *Automated Switch Teams*

We have installed automated switch teams on portions of our distribution system. These teams automatically sectionalize and isolate the faulted portion of a circuit. After sectionalizing and isolating the fault that is disrupting power on the system, power is restored to the un-faulted portion of the circuit, restoring power to customers on that portion of the circuit. While not being totally "self-healing," this does allow the maximum number of customers to be automatically restored after an event, leaving fewer customers with a sustained outage.

NSPM now has 74 of these switches operating in Minnesota. We deploy these based on circuit length and customer count, and are currently installing three to five additional switches per year. In 2012, NSPM launched a program to replace all the Remote Terminal Units on switches. This will bring our switches and operating systems to the current available versions, better ensuring proper operation and continued support by the vendor. This project was completed June 1, 2013. Additionally in 2013, we implemented a tracking tool to track the operating status of the teams, and how many Customer Minutes Out (CMO) have been saved by the switches.[6] In 2013 these switches saved over 12 million CMO, which is a direct improvement to our customers' reliability experience.

2. Remote Fault Indicators

These devices identify high current flow, indicating that there is a fault downstream of the device, which then uses a cellular phone to report that it has seen fault current pass through it. This information is then displayed to the System Operator, who couples it with other information, allowing us to begin restoring power to customers without first physically patrolling the area.

This greatly reduces customer outage time, and enables restoration to begin on the un-faulted portions of the circuit. We deploy these devices at key points on the distribution system at switches and lines that cannot be readily patrolled. NSPM currently has 125 of these devices in use. These devices were installed in the early 2000's. The devices and this technology are reaching the end of their life, so as devices fail, they are being removed from service. We currently are searching for a viable replacement.

3. Smart Substation

This leading-edge demonstration project retrofits the existing Merriam Park substation with cutting-edge technology for remote monitoring of critical and non-critical operating data. The project was to have also included an analytics engine that processes massive amounts of data for near real-time decision-making and automated actions. During 2011, we ended our efforts with the vendor that provided this equipment because they were not dedicating sufficient resources toward getting the necessary functionality up and running. So, while we have more robust operating data and increased data capabilities, instead of it being automatically generated, we must acquire the required data for strategic decision-making. We continue to install leading edge technology in our substations that includes capabilities for information storage and other features including Phasor Measurement Units, which provide highly accurate electrical system state to the operators. This operating information will improve our post-event analysis and system state estimation capabilities in our new Energy Management System that we expect to implement in 2015.

[6] CMO equals the total minutes of a sustained outage event multiplied by the number of customers impacted.

4. SmartVAR

In 2010, we implemented a SmartVAR Management pilot program associated with our Energy Innovation Corridor in St. Paul, MN (*See* Docket No. E002/M-09-1488). This pilot project tested the effectiveness of "smart," or automated, capacitor controls that have two-way communication ability to manage reactive power (Voltage Ampere Reactive power or VARs) on a portion of our distribution system. The automated capacitor control program is fed information from our SCADA system, and based on this information, the capacitor control system switches capacitors on and off to manage reactive power levels on the distribution Feeder. Managing reactive power reduces system losses by increasing system efficiency.

The results of the pilot were very positive, providing improved power quality and availability to customers, as well as reducing emissions through improved line loss reduction. Based on the positive results from the pilot program, in 2012 we began a five-year project to replace all (approximately 2,100) current capacitor controls in NSPM with controllers capable of two-way communication. Through 2013, we have replaced 1,010 controllers and are scheduled to replace an additional 360 controllers in 2014, with similar levels of annual replacements occurring through project completion (December 31, 2016). We note that we provide quarterly and annual updates regarding this initiative in Docket No. E002/M-09-1488. The cost incurred during 2013 was approximately $900,000.

5. MISO Smart Grid Project

In March 2010, the MISO launched a program to install more than 150 high-tech monitoring devices across its footprint that would monitor the state of the electrical grid 30 times each second at these points. The objective for the project is to improve power system reliability and "visibility" through broad-based system monitoring and control.

a. Project Overview

The devices being installed by the Company and other MISO entities are called Synchrophasors. These devices provide precise measurements of what is going on at particular points or segments of the transmission system, which is "time-synced" to the GPS Satellite System, synchronizing the system information across all MISO and other entities nationally. While these devices were beta-tested as stand-alone devices in the 1990s, they have since matured to commercial grade, and their use is further enabled by improvements in network communications capabilities necessary to handle and provide consistent, high-volume data.

This initiative is being conducted in phases, and will generally be on the highest voltage portions of the transmission system. Phase I began in October 2011 and ended March 31, 2013. During that phase, we installed a total of 27 devices in nine substations, 22 of which were installed in eight different substations in Minnesota. Phase II began January 1, 2013 and will end March 31, 2014. During Phase II, we expect to install a total of 30 devices in 10 different substations, again, with the bulk of these devices (28) installed in Minnesota substations (9). As of December 31, 2013, we had installed all 28 of the devices planned for Minnesota as part of this Phase.

MISO is partially funding this initiative through a DOE stimulus grant, with total project costs being funded through the MISO tariff. Therefore, the costs the Company is incurring directly will be reimbursed by MISO. We estimate our total direct costs for this initiative, subject to reimbursement from MISO, will be approximately $3.3 million; to-date, we have incurred approximately $2.8 million associated with our participation in this initiative.

b. Synchrophasor Functionality

Synchrophasors capture and provide the following data *30 times per second*: 3-phase current, 3-phase voltage, positive sequence voltage, positive sequence current, frequency, and phase angle data. As noted earlier, this information is time-synced, so all of these devices, regardless of their location or the entity whose system they are installed on, are "in sync." Comparatively, on the portions of our transmission system that do not have Synchrophasors installed, we receive more limited information, generally on a *4-second* basis: voltage, VARs, and total MW. Further, this information is not time-synced across MISO entities.

c. Benefits of Synchrophasor Technology

Although there are many expected benefits of this technology, an immediate benefit from installation of this technology is a "real-time" gauge of the stress and balance on the transmission system. Without this technology, we must conduct periodic offline studies to determine the operating guidelines for each line. These guidelines provide the parameters that system operators must operate within to ensure that the grid remains stable. Conversely, Synchrophasors measure phase angle data 30 times per second, informing the operators in real-time the level of balance on the system. This real-time information allows the operators to more closely monitor and take more informed actions to balance the system.

Other benefits include improved "event" analysis. By receiving multi-faceted information regarding the power flowing through the system at a given point in time *30 times per second* – synchronized across all entities – we (and others, such as NERC) will be much better-equipped to understand, analyze, and learn from disturbances or other system events.

d. Next Steps

As of December 31, 2013, we have installed 57 devices in 19 substations on our transmission system, 50 of which are in 17 substations in Minnesota. We will be working toward further leveraging of this data into our systems, which will allow us to further assess and realize the expected benefits of this technology.

6. Wind-to-Battery Storage

The Wind2Battery (W2B) system became operational in late 2008. This project tested a one-megawatt battery energy storage system connected directly to a wind farm in an effort to store wind energy in batteries and return it to the grid. Fully charged, the battery could power 500 homes for more than seven hours. Benefits include expected long-term emission reductions from increased availability of wind; reduction of impacts of wind variability; modernization of the grid to allow for easier integration of renewable energy sources; and allowing us to meet Minnesota Renewable Energy Standard legislative requirements. *Cost:* Approximately $4 million.

The W2B project has provided us with experience and information that will allow us to assess and improve upon the viability of scaling-up battery storage on our system as more wind power is added to meet the renewable policies in the states we serve. The original testing has now been completed, and the results of that testing can be found in our final report filed on January 10, 2012 in Docket No. E002/AI-09-379.[7]

We note that during much of 2012 the battery system was shutdown as a precautionary measure at the recommendation of NGK (the battery manufacturer), after we learned of a fire at a similar NGK installation in Japan in 2011. NGK has since conducted a thorough analysis of the situation and its root causes and redesigned the battery modules. All battery modules at our Luverne, MN installation were replaced with brand new modules of the new design, which was completed in November 2012.

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[7] A public version of the report is also available at: http://www.xcelenergy.com/staticfiles/xe/Corporate/Renewable%20Energy%20Grants/Milestone%206%20Final%20Report%20PUBLIC.pdf

Following completion of the battery module replacements, the energy storage system was placed back in service providing regulation services to store, control and dispatch energy when needed for supply or transmission stability purposes. Late in the third quarter of 2013, the Company initiated some upgrades to the communication system, which took the battery out of service. At the time of this report, we are still completing these upgrades at the site, and expect to be back online soon, at which time we expect to continue to operate the battery in the MISO market.

C. Automated Meter Reading

Our current metering strategy is to leverage our existing Cellnet Automated Meter Reading system and improve related processes. In addition, we continually look for opportunities to leverage existing rates and AMR infrastructure to pilot future programs. It is also our intention to assess how we might utilize the Network Communications Strategy efforts discussed in Section A of this report to improve our cost effectiveness and the viability of various Advance Metering Infrastructure (AMI) technologies in the future.

Currently, our AMR system collects on-cycle automated reads for billing purposes for residential meters and demand meters. It also collects daily reads that can be used for customer account analysis, if needed.[8] In contrast to AMR, AMI technologies facilitate real-time, on-demand meter reads and other communication with the meters.[9] Among other things, AMI systems can perform remote service disconnects and reconnects, allow automated net metering, transmit demand-response and load-management messages, and interrogate and control distribution-automation equipment.

Below we provide a chart showing the breakdown of our existing meters by electric/natural gas, customer type, and whether they are AMR-capable.[10] We do not currently have any AMI metering installed in Minnesota.

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[8] The data collected for residential and small commercial customers is typically aggregated kWh consumption. For all customer types, residential, small commercial, commercial or industrial, the type of data collected can be one or a combination of kWh aggregated consumption, on-peak/off-peak kWh, daily peak demand, daily demand off-peak/on-peak readings, and/or reactive energy readings depending on the specific tariff/rates applicable to the customer.

[9] The Federal Energy Regulatory Commission (FERC) defines AMI as a metering system that records customer consumption hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point.

[10] Data as of December 31, 2013.

Existing Meter Counts and Capabilities
State of Minnesota

		AMR-Capable?		
	Customer	**Yes**	**No**	**Total**
Electric	Residential	1,125,763	101	1,125,864
	Commercial	121,885	1,089	122,974
	Industrial	5,129	3,100	8,229
	Government	3,040	404	3,444
Gas	Residential	413,891	1	413,892
	Commercial	34,655	391	35,046
	Industrial	323	179	502
	Government	649	26	675
	Total	***1,705,335***	***5,291***	***1,710,626***

Our current AMR system, which provides automated meter readings for the majority of our customers, has resulted in reduced meter reading costs and resource requirements, and in most cases, more consistent meter reading performance as compared to manual meter reading. In addition, our AMR system provides additional information to the billing, meter reading, and metering departments to better analyze and respond to billing inquiries and potential meter equipment issues. And, as noted in Section A.3 above, we are leveraging our AMR system, which has enhanced our outage management and service restoration capabilities.

D. Customer Access to Data

We collect, use, maintain and share customer-specific data to provide regulated natural gas and electric service to our customers. We are committed to providing our customers with access to their information, protecting our customer's information, and being transparent about our data privacy practices. In this section, we outline the information, programs, and tools we currently offer to our customers, which we believe empowers them to both control and use their information in a number of ways. We note that we are participating in the Commission's proceeding in Docket No. E,G999/CI-12-1244 that is examining the privacy practices of Minnesota's energy utilities. The customer information access and programs we discuss in this section are not generally the focus of that proceeding. We include, however, an overview of our customer data privacy policy as Part 5 of this section.

1. *Usage and Billing Data*

Residential and small business customers, as well as all public sector customers, are able to view their energy usage through the My Energy portal in My Account on xcelenergy.com. In the portal, customers can track their energy usage and bill information over time, as well as see how their energy consumption compares to other customers similar to them. Customers can access their historical data through Green Button Download My Data functionality, which provides up to five years of monthly usage information in either xml or csv format. Larger customers can view their usage data and account information at xcelenergy.com through My Account, where up to 24 months of usage history can be retrieved in csv format. Customers can also call to request historical usage information, which will be returned in spreadsheet format.

2. *Outage Data*

At xcelenergy.com/outages, we provide customers the ability to view current electric outages on a map; we also provide the start time of the outage, as well as an estimated restoration time. We launched this customer information tool in March 2010. The information provided by this website tool stems from our NMS, and is updated every ten minutes. Customers can zoom into an approximate 2.5 mile area on the map; it does not provide specific premise/address information. The maps provide aerial pictures, a legend indicating the number of customers impacted, and other detailed information to aid customers and the media in understanding the scope and scale of outage events.

3. *Xcel Energy Mobile Access*

In November 2012, Xcel Energy launched a mobile website (*m.xcelenergy.com)* for customers to access Xcel Energy on their smart phones. This mobile website offers all customers visibility to products, services, energy-saving ideas, safety tips and outage information in another convenient, timely, easy-to-use manner via their smart phones. Customers accessing Xcel Energy's main Internet site (xcelenergy.com) from smart phones, are redirected to the mobile website, with an option to instead view the full website.

The main menu on the mobile homepage provides:

- Pay Your Bill
- Outages
- Rebates

- Energy Saving Tips
- Call Before You Dig
- Contact Us
- Colorado Solar
- Link to xcelenergy.com website
- Links to Xcel Energy Facebook, Twitter, YouTube, Blog, Pinterest, LinkedIn

We have identified the most common tasks customers look to complete with us and we have made and continue to make enhancements to ensure these tasks can be performed in a preferred channel through a streamlined delivery. We believe our addition of mobile access to information and ability to interact with the Company meets our customers' expectations and provides significant value.

4. Energy Feedback Pilot Program

Energy Feedback transitioned from pilot to program in 2013. The program provides participating customers information about their energy consumption and about how that consumption compares to similar homes nearby. This is an opt-out program that uses the participant and control group to determine how much energy was saved by the participants. As part of the transition from pilot to program, 100,000 new customers were added to the program. Currently the program follows savings from four groups: the original participants, customers who receive only email notifications, participants selected to "refill" the original group, and the newest expansion group.

As mentioned above, the Energy Feedback Pilot became a program in 2013. As part of this transition, the program went from reporting 100 percent of savings to using the Average Savings Method (ASM), under which, the life is assumed to be 1.0 years and energy savings are reduced by 2/3 annually via a Behavior Adjustment for utility goal calculations.

Late in 2013, we filed for and received approval from the Department of Commerce to add Online Energy Feedback as a new measure within the existing Energy Feedback program. These tools and services allow any customer to login through My Account at xcelenergy.com, and see My Energy comparisons to peer energy use, and an online usage analysis that evaluates equipment and savings suggestions similar to an online audit. This tool encourages goal setting and tracks action customers take to save energy and how they are performing against goals. Making these tools available to all customers encourages everyone to engage in behavior-changing activity to save on energy and help the environment. In addition to empowering customers with more interactive tools and services, we will begin to monitor and measure savings attributable to online energy feedback in 2014.

Energy Feedback did not meet its gas and electric savings goals in 2013. We believe this is due in large part to an underestimation of the time needed to ramp up the savings behaviors of the new customer group, which comprised over 50 percent of total participants. The achievement gap is larger for natural gas; as we have noted, our filed gas goals were based on savings projections that were higher than realistically achievable. Finally, the savings reported also reflect an 11-month time frame as opposed to a full calendar year. Because savings are determined using actual customer data and because of the large number of participants, data is unavailable until at least three weeks after the reporting month ends. For this reason, we decided to close the program year with November 2013 results. The 2014 program results will include savings from December 2013, along with a minimal 2013 "true-up" that the vendor calculates. This true-up adjusts savings to account for behavioral program savings that could be attributed to stand-alone rebate program participation.

In addition to the residential program, we plan to launch a Business Energy Feedback Pilot in 2014. This pilot will test the responsiveness of the small/medium business market to behavior-changing recommendations appropriate for the customer's business segment. We will measure energy savings associated with these Business Energy Feedback reports to determine whether they offer a cost-effective opportunity for additional energy savings and engagement in this traditionally hard-to-reach market sector.

5. Customer Data Privacy Policy Overview

As we noted previously, we collect, use, maintain and share customer-specific data to provide regulated utility service. Absent a legal requirement, we will not further distribute customer-specific data for secondary purposes without first obtaining the customer's explicit consent. We believe that our data practices appropriately balance our business needs with the customer's interest in controlling access to their unique information. The data access tools we discuss in this section demonstrate ways that we empower our customers to control and use their energy usage data in several ways.

We are active participants in matters at both the federal and state level addressing issues of customer privacy and data access, including the Commission's current inquiry in Docket No. E, G-999/CI-12-1344. We believe that it is important to have an open dialog on these issues, as concerns about privacy can negatively impact our relationship with our customers, regulators and other stakeholders. Our goal is to be the trusted provider of our customer's energy needs, and we recognize that maintaining appropriate data practices is an important aspect of that trust. We look forward to working together with other stakeholders to codify appropriate privacy standards for utilities in Minnesota.

Our current privacy practices are further outlined in our Privacy Policy, which is available through a link at the bottom of every page on our website (xcelenergy.com).

E. Time-Varying Rates and Demand Response

Time-varying rates separate an average standard rate into a lower "off-peak" rate and a higher "on-peak" rate. This provides customers with an economic incentive to shift energy use from higher-cost "on-peak" hours into lower-priced "off-peak" hours. Demand response rates provide a rate discount as an incentive for customers to agree to curtail their usage during Company-declared system-peak conditions.

1. Time-Varying Rates

Xcel Energy offers time-varying rates to both residential and business customers. The residential Time-of-Day (TOD) rate is optional. TOD rates are mandatory for business customers with peak loads of 1,000 kW or greater, and are optional for other business customers. We discuss our various TOD rates below.

a. Residential Time-of-Day Rate

As an optional alternative to Residential Service, Residential TOD Service rates apply to all household energy usage. This optional service provides a discounted rate to customers for their energy used during off-peak hours. The off-peak rate is approximately one-third of the standard residential base rates, while the on-peak rate is approximately twice the standard rates, but varies based on season and heating type.

This TOD rate option typically reduces electric bills for customers that use at least 650 kWh/month, and that have electric heat or water heating or other major loads that can be shifted off-peak. To experience savings on this rate option, customers must use approximately 65 percent or more of their overall electric usage during off-peak periods, which are 9:00 PM to 9:00 AM weekdays and all hours on weekends and specific holidays.

A three-month trial period for Time-of-Day service is available to residential customers. Customers that choose to return to non-Time-of-Day service after the trial period are responsible to pay a charge of $20.00 for removal of the Time-of-Day metering equipment.

After the trial period, customers electing the TOD rate option must remain on the rate for 12 months. Currently, 392 Minnesota customers are enrolled in our residential TOD option.

As we also discuss in Section F below, we continue to promote our existing TOD rate options to electric vehicle (EV) drivers to encourage charging during off-peak times, ensuring they are aware of the opportunity to reduce bill impacts associated with vehicle charging. The Company may also benefit from our EV customers participating in the TOD rate options, in that it may help mitigate potential stress to the distribution system caused by EV charging.

b. Business Time-of-Day Rates

We have three Business TOD Rate options that provide discounted rates to non-residential customers for their energy used during off-peak hours.

- *Small General TOD.* This rate option is available to non-residential customers with a maximum load less than 25 kW. Customers may elect this TOD rate for a trial period of three months. If a customer chooses to return to non-TOD service after the trial period, there is a $25 charge for the removal of the TOD metering equipment. We currently have 10,001 customers on this rate.

Demand-metered non-residential customers that have a peak load of 1,000 kW or greater for at least four of the past 12 consecutive months must take a TOD service schedule – either General Service TOD or Peak Controlled TOD. Customers choosing the Peak Controlled TOD rate receive a demand charge discount in exchange for agreeing to control their demand to a pre-determined level when Xcel Energy calls for such control. Additional applications of the General TOD and Peak and Energy Controlled TOD services are as follows:

- *General TOD Service.* Non-residential customers with demand metering that are not required to be on a TOD rate may elect to take TOD service. We currently have a total of 3,850 customers on this rate.

- *Peak and Energy Controlled TOD.* This rate is available to non-residential customers with a minimum controllable demand of 50 kW, who agree to control their demand to a pre-determined level when Xcel Energy calls for such control. We currently have a total of 2,022 customers on these rates. Customers on these rates receive up to a 54 percent reduction on the demand charge for their controllable load, at the secondary voltage service level. Under the Energy Controlled rider option, customers also receive a reduced kWh rate on their controllable load, in exchange for more hours that the Company can potentially interrupt their load.

c. Limited Off Peak Rate

The Limited Off Peak rate option offers a reduced energy rate to residential and small commercial customers for specific electric equipment operating between 10:00 PM and 6:30 AM, seven days a week. Two installed electric meters allow for the standard kWh rate to be applied to energy recorded on the first meter for regular household usage while the lower rate is applied to energy recorded on the second meter for specific appliances. Customers with electric thermal storage heating, radiant floor heat, or electric water heaters that store electric heat during off-peak periods for use during the next day's on-peak period will benefit the most.

To take advantage of savings that this rate offers to certain customers, customers must pay an additional monthly service charge for the additional metering and billing requirements. Also, customers are subject to a $0.26/kWh charge for any energy use that is served through the off-peak meter that is outside the authorized off-peak period. Customers must remain on this rate for a minimum of twelve months, unless they transfer to another interruptible service rate. Currently, 465 Minnesota customers (380 residential, 85 commercial) are enrolled in the Limited Off Peak rate option.

d. Real Time Pricing Service

The RTP rate option is available to customers with a minimum peak load of 1,000 kW. RTP service includes energy charges for eight different types of days, with six different pricing periods within each day-type. RTP customers select a contract demand level for demand billing and pay an additional energy charge for loads over that level except for the two lowest priced day-types. This design provides pricing incentives that are closely matched to both high and low cost conditions. There is currently one customer with two accounts enrolled in this program.

2. Demand Response Programs & Interruptible Rates

Xcel Energy has three electric load management programs as follows: (1) Electric Rate Savings; (2) Saver's Switch; and (3) Energy Controlled Service. These programs provide customers rate discounts for reducing electric load on days having peak demand for electricity. The table below identifies the current contracted customer load and customer participation for each program.

Demand Response and Interruptible Rates Participation
State of Minnesota

Program	Controlled Load (MW)	Customers
Electric Rate Savings Program	488	2,025
Saver's Switch-Business Customers	45	15,917
Saver's Switch-Residential Customers	229	376,858
Energy Controlled Service	n/a	3,092
TOTAL	***762***	***397,892***

Data as of December 31, 2013.

a. Electric Rate Savings Program

The Electric Rate Savings Program is marketed as the Peak Controlled and Energy Controlled Rates to customers. Participants receive a monthly discount on their demand charges in return for reducing electric loads when notified by Xcel Energy. Customers on the Energy Controlled rate also receive a reduced kWh rate on their controllable load, in exchange for more hours that the Company can potentially interrupt their load. Customers must be able to reduce their electric loads by a minimum of 50kW on control days. Participants save as much as 58 percent on secondary voltage demand charges over the entire year for the demand they commit to reduce during control periods. Minnesota participation in this program in 2013 was approximately 2,025 customers.

b. Saver's Switch – Business Customers

Saver's Switch for business customers is a direct load control program. Participating customers receive a monthly discount of $5 per enrolled ton of air conditioning during the months of June through September. In exchange, Xcel Energy has the ability to control electric central air conditioners on days of peak electric demand. Minnesota participation in this program in 2013 was approximately 15,900 customers.

c. Saver's Switch – Residential Customers

Saver's Switch for residential customers is a load management program that provides direct load control of central air conditioners and electric water heaters. Participants in the central air conditioning program receive a 15 percent discount on their June through September electric energy and fuel cost charges. These participants are eligible to receive an additional two percent discount for enrolling their electric water heater. Water heaters can be controlled year-round, and the associated water heater discount applies year-round as well. Minnesota participation in this program in 2013 was approximately 377,000 customers.

d. Energy Controlled Service (Non-Demand Metered)

We additionally offer a program for new or existing Minnesota electric customers (Rate A05), whose home or business has a primary electric heat source and an alternative fossil fuel heat source. The program offers customers the opportunity to save money on their electric heating costs by allowing Xcel Energy to control (interrupt) their primary electric heat source, during peak heating times (October – May). During an interruption, customers must be able to switch to their backup/dual fuel heat source. There are two options: Standard energy control rate and Optional energy control rate (allows Heat Pumps to be controlled during the summer months). Minnesota participation in this program in 2013 was 3,092 customers.

F. Electric Vehicles

The Commission has previously expressed interest in EV initiatives as part of this docket, so we provide an expanded EV discussion below, updated for this 2013 report:

We believe utilities will necessarily play a critical role in enabling alternative transportation markets. In 2013, leading automotive manufacturers developed additional EV models to provide to the public for passenger vehicles, as well as medium and heavy duty options for business-oriented use. While EVs have seen double-digit growth, adoption appears to be following the slower growth scenarios, as indicated on previous industry projections.[11] Still, based on customer interest and industry development, Xcel Energy continues to anticipate future needs to fulfill the role of providing the energy to power alternative fuel vehicles in a safe, reliable, and cost-effective manner.

1. EVs at Xcel Energy

Since 2011, Xcel Energy has had a "Repowering Transportation" team that includes representatives from across the Company, to assess and prepare for the greater utilization of EVs and other alternative fuel vehicles, such as Compressed Natural Gas (CNG). The team has been charged with developing and implementing a

[11] Electric Drive Transportation Association tracked 52,835 plug in electric vehicle sales in 2012 and 96,702 in 2013. *See* http://electricdrive.org/index.php?ht=d/sp/i/20952/pid/20952

comprehensive strategy to address clean transportation issues.

In 2013, we continued to implement the communications program the team developed to educate our customers, and engage with other interested stakeholders. We use xcelenergy.com, the Connect Blog, printed brochures and other materials to provide relevant information about electric vehicle programs, technologies, and news.[12] We have, and will continue, to adopt alternative vehicles into our own fleet, to investigate the impacts of EVs on our distribution system, and to develop collaborative relationships with external stakeholders. In 2013, we observed a full year of the fee-based employee charging pilot program we developed in 2012 to improve our understanding of costs and benefits associated with businesses offering EV charging services to employees. We plan to continue the pilot as more employees adopt electric vehicles.

2. Collaboration

We continue to participate in Drive Electric Minnesota (DEM), which is a partnership among Xcel Energy, local and state governments, as well as private and non-profit business entities working to bring electric vehicles and plug-in charging infrastructure to Minnesota. DEM's goals include encouraging the deployment of EVs and the establishment of a charging station infrastructure.

Through the Chairman's fund in 2010 and 2011, Xcel Energy has collaborated with DEM to help facilitate purchases of 14 Transit Connect electric vehicles for demonstration in highly visible fleets. Additionally, in 2012 and 2013, Xcel Energy supported the installation of 92 public charging stations in key locations at city, university, and public transit locations by leveraging an Xcel Energy contribution with additional federal and local grant funds. The Company continues to work with DEM to complete the installation of these charging stations while also promoting the Zero Emissions Challenge to encourage renewable energy offsets for the charging stations.[13]

3. Utility System Impacts

In the small but growing EV industry, adoption rates of electric vehicles are still uncertain. Building upon external projections and using an econometrics model, the Company created a projection of the demand and energy sales impact of EVs in NSPM's service territory. Using these projections and peak transformer load data, we

[12] We note that we additionally provide educational materials regarding natural gas vehicles.
[13] *See* http://www.energyinnovationcorridor.com/page/showcase/drive-electric-mn/

have analyzed scenarios representing different penetration levels of EVs.

We continue to expect generation and transmission capacity will be sufficient to meet demand, even under aggressive scenarios over the short- and medium-terms. While we expect EVs to represent a higher than normal load increase, we believe that we will be able to effectively manage the total load that they may put on our system. We are accustomed to dealing with increasing loads, and have the tools and practices in place to make the capacity planning decisions necessary to accommodate the additional load caused by EV charging.

However, although we expect generation and transmission capacity to be sufficient, actual distribution system impacts are difficult to predict due to unknowable details. Our analysis indicates that there are potential impacts to the distribution system, the extent of which will depend on customer EV adoption levels and the geographic patterns/clustering that occurs.[14] However, we are aware and taking additional steps such as collaborating with auto manufacturers to gather information on the geographic location of EVs for planning and mitigation of system impacts.

The electric infrastructure exists today to fuel EVs. As customer adoption of EVs rises, we will continue to closely monitor and manage transformer loading and other system impacts stemming from the incremental load from EV charging.

4. *Customer Charging Behavior and Programs*

When customers increase their usage of electricity, the cost to a utility (and ultimately other customers) depends upon the point(s) at which the increased usage occurs. While it appears that the majority of EV charging activity is occurring at drivers' residences, public and workplace charging options continue to increase.

As noted previously, we continue to market our existing TOD rate option to EV drivers, to encourage charging during off-peak times. This has the potential to provide both customer and Company benefits. Customers have the opportunity to reduce bill impacts, and customer enrollment in TOD options may allow the Company to mitigate potential stress to the distribution system caused by EV charging.

We have also developed a marketing campaign, *Drive with GUST-o,* which educates our EV-owning customers how they can power their vehicle with Windsource for

[14] An EV charging at 6.6 kW (Level 2 charger) is similar to the peak load of an entire home. Distribution transformers generally serve between 5-15 homes; depending on the existing transformer load, incremental load from multiple EVs could cause the transformer to overload.

emissions-free driving at home. And, as noted above, the DEM Zero Emissions Challenge initiative targets WindSource participation for public charging infrastructure in public and workplace locations.

We desire to support customers in their adoption of technologies that will help them manage their environmental impact and energy use, whether that is for their home or transportation. NSPM will continue monitor EV-related activities throughout the United States and evaluate opportunities to provide EV-related programs that are cost-effective for both our EV-owner customers and other customers.

5. EV impact on "Smartgrid"

Based on our current knowledge, we do not believe that Smartgrid technologies, such as smart meters, or transformer monitoring, are essential to reducing the short-term impact of EVs on our system. However, we do believe that these technologies would assist in discovering or anticipating issues on the local distribution grid and could provide benefits to both EV owners and the Company. Any system issues resulting from EV charging are dependent on adoption rates and charging behavior, which today are not fully understood due to the stage at which we are in Minnesota.

Customer behavior modifications, such as charging vehicles off-peak, may be sufficient to mitigate any issues and may not require Smartgrid technology, depending on its form. We are continuing to monitor and participate in customer behavior studies that will provide more information on EV impacts and mitigation strategies. As with any system modification or modernization, we will evaluate and balance the cost-effectiveness of emerging technologies to ensure it will provide value to our customers.

Conclusion

Xcel Energy respectfully requests the Commission accept this 2013 Annual Report.

Dated: April 1, 2014

Northern States Power Company

RESPECTFULLY SUBMITTED,

/s/
By: ____________________________
PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE & FILINGS

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. E999/CI-08-948

Dated this 1st day of April 2014

/s/

____

SaGonna Thompson
Records Analyst

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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Paper Service	No	OFF_SL_8-948_1
Darrell	Gerber		Clean Water Action Alliance of Minnesota	308 Hennepin Ave. E. Minneapolis, MN 55414	Paper Service	No	OFF_SL_8-948_1
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_8-948_1
Mark	Glaess		Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Paper Service	No	OFF_SL_8-948_1
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	No	OFF_SL_8-948_1
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_8-948_1
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_8-948_1
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_8-948_1
Paula N.	Johnson	PaulaJohnson@alliantenergy.com	Interstate Power and Light Company	200 First Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_8-948_1
Larry	Johnston	lw.johnston@smmpa.org	SMMPA	500 1st Ave SW Rochester, MN 55902-3303	Paper Service	No	OFF_SL_8-948_1

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John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_8-948_1
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_8-948_1
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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